

Carbon Intensities of Refining Products in Petroleum Refineries with Co-Processed Biofeedstocks

Energy Systems Division

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ABSTRACT

Petroleum refineries increasingly seek to generate fuels with lower carbon intensities (CIs; a measure of life cycle greenhouse gas [GHG] emissions per unit of energy of fuel; well-to-wheel [WTW]) to meet growing demand. *Co-processing* refers to a process that adds biomass-derived feedstocks to the fossil-based feedstocks of existing petroleum refinery process units. With the use of biofeedstocks, it is expected that co-processed fuels would have lower CIs than their petroleum counterparts without requiring changes in the existing infrastructure for producing, transporting, and using fuels.

To quantify the GHG emissions reduction benefits of co-processing, this study uses a linear programming model to simulate petroleum refinery conditions with and without co-processing. The co-processing cases include three biofeedstocks (soy oil, tallow, and used cooking oil or UCO) used as 10 vol.% of the feedstock to a hydrotreater or hydrocracker since these lipid-based feedstocks have favorable properties to be treated in a hydrotreater or hydrocracker. In addition, we considered pyrolysis oil used as 10 vol.% of the feedstock to a fluid catalytic cracking (FCC) unit in the modeled refinery due to its higher oxygen content compared to other lipid-based feedstocks.

Life cycle analysis (LCA) using two distinct approaches—process-level energy allocation and a refinery-level marginal approach—has been conducted for each case. The LCA results using process-level allocation show that there are no noticeable changes in emissions or energy use impacts at the facility level. The life cycle GHG emission reductions of co-processing cases are mainly related to the fraction of biogenic carbon embedded in each fuel product. For example, co-processed jet fuels (a mixture of fossil and biogenic fuels) made via hydrotreating or hydrocracking have higher biogenic carbon, which results in jet fuel CI reductions of 3.9%–8.6% compared to the CI of baseline petroleum jet fuels on a WTW basis. However, analysis of co-processed pyrolysis oil in an FCC shows that a higher fraction of biofeedstocks (29%) becomes process emissions (i.e., CO and CO₂), mainly due to the oxygenates in pyrolysis oil, and so it generates less renewable fuel than biofeedstocks co-processed via hydrotreating or hydrocracking.

Using the refinery-level marginal approach, the changes in energy use and emissions of co-processing cases compared to the petroleum-only baseline case are allocated to the changes in fuel production (assuming renewable fuels). This approach generates the life cycle GHG emission values of co-processed renewable fuels, which are comparable to the CIs of standalone biofuel production pathways. However, as this approach relies on a rough assumption that product yields and emissions from co-processing units on fossil feedstocks remain the same with and without biofeedstock inputs, co-processing cases like FCC pyrolysis oil may generate quite skewed results.

Keywords: co-processing, carbon intensity, life cycle analysis, greenhouse gas emissions, well-to-wheels, petroleum refinery, biofuels, lower carbon intensity fuels

1. INTRODUCTION

As demand for renewable or lower-carbon fuels with low life cycle greenhouse gas (GHG) emissions is expected to grow in the future, co-processing of biofeedstocks (biomass-derived feedstock) in existing petroleum refineries can be integral to the solution, as they enable refiners to use existing infrastructure and reduce carbon intensities (CIs) of drop-in fuels. Major crude oil refining companies, such as Phillips 66, BP, Marathon, ExxonMobil, and Chevron, are considering co-processing to produce fuels with lower CIs in existing refinery facilities with minimal capital investments (Gallagher 2018, Sanicola 2020, Sciacca 2020, Elliott 2020).

Co-processing refers to an operation that introduces biofeedstock-derived oils, such as soy oil, tallow, used cooking oil (UCO), or pyrolysis oil, into specific process units in existing petroleum refineries along with crude-oil-derived streams. Because the carbon in biomass-derived feedstocks is from the atmosphere, biogenic carbon emissions are carbon-neutral, which results in biofuels with lower CIs than fossil fuels. Thus, co-processing can bring GHG emissions reduction benefits, which can potentially lead to monetary credits through various regulatory frameworks aiming to reduce or offset carbon emissions.

Co-processed fuels are compatible with existing petroleum fuels. For example, the American Society for Testing and Materials (ASTM) standard ASTM D1655-19 specifies that biofeedstocks—up to 5% by co-processing unit volume—can be processed either through hydrotreating or hydrocracking to become aviation fuels. Note that co-processing is different from blending biofuels into the final petroleum products: “Blending” refers to physical mixing of biofuels and petroleum fuels after they are generated in separate facilities, while “co-processing” occurs in the units in a refinery.

Life cycle analysis (LCA) is used to evaluate GHG emissions reduction benefits by comparing the CIs of fuels produced in new ways with baseline fuels. LCA accounts for all the emissions associated with a fuel’s production, all along the supply chain, for a consistent comparison. For example, for petroleum-derived fuels (e.g., petroleum gasoline, diesel fuel, and jet fuel), an LCA covers crude oil recovery, crude oil transportation, crude oil refining, fuel transportation and distribution, and fuel combustion. In an LCA, all indirect emissions from the use of energy (e.g., electricity) and materials (e.g., chemicals) are accounted for as well as all emissions from each stage. Similarly, the supply chain of biofuel production includes biofeedstock production (e.g., soybean farming for soy oil), biofeedstock transportation, biofuel production, biofuel transportation, and biofuel combustion.

Previous studies on co-processing focus on the feasibility of various combinations of biofeedstocks and insertion points in petroleum refineries (Bezergianni et al. 2018). Bezergianni reviewed recent studies on co-processing and identified the types of biofeedstocks—including lipids, edible/non-edible oils, biomass residual oils, and pyrolysis oils—that can potentially be co-processed in hydrotreaters, hydrocrackers, and fluid catalytic cracking (FCC) units in petroleum refineries. The studies reviewed in that paper mostly presented the feasibility of co-processing in terms of potential feedstocks, catalysts, and operating conditions (Bezergianni et al. 2018). Although these are important factors for a successful co-processing operation, the main driver for co-processing is its GHG emissions reduction potential, which needed further quantification.

Garraín et al. (2014) used co-processing test runs in a petroleum refinery for an LCA to evaluate the well-to-tank GHG emissions of co-processed soybean oil inserted into a hydrotreating unit. The LCA results showed that, with a co-processing level of 9%–14%, well-to-tank GHG emissions would be reduced by 9% compared to a blend of petroleum diesel and typical biodiesel produced through fatty acid methyl ester (FAME). Although that study presented potential GHG emissions reductions through co-processing,

it has several limitations: For example, the authors assumed that there were no changes in refinery emissions and energy inputs without investigating the impact of the input changes. Also, typical refineries have various products that generally require process-level energy allocation to properly allocate energy use and emissions to each product. However, the study assumed that naphtha and hydrocarbons are the only co-products of the system evaluated. Most significantly, the system boundary of the study ends at the fuel production stage (i.e., it is well-to-tank [WTT]), and it includes only one specific co-processing case (soybean oil in a hydrotreater). Since the majority of the GHG emissions reduction may be obtained through biogenic carbon in the fuel products, it is essential to examine all life cycle stages (well-to-wheels or well-to-wake [WTW]) to quantify GHG emissions reduction benefits through co-processing.

Along with evaluating GHG emissions from co-processing refineries, it is important to quantify the amount (volume) of the biogenic portions in the co-processed final products. Evaluating renewability has been a major topic in regulatory frameworks because only the biogenic portion of the produced fuels would be eligible for emission reductions, while there is no physical distinction in the final fuel product that indicates how much carbon is from biogenic or fossil sources. Several biomass quantification accounting methodologies have been proposed to quantify this, including measurement using carbon-14 (^{14}C) and various methods of estimation, such as incremental yield, free attribution, and mass-, carbon-, or energy-based equal attribution. However, these efforts focus only on carbon tracking or carbon allocation without considering the implications for GHG emissions. Even if we can precisely estimate how much biogenic carbon ends up in each fuel product, we still need to allocate emissions to the individual energy products.

Despite growing interest in co-processing, no previous studies have provided WTW GHG emission results for co-processed fuels that consider all these aspects, especially for multiple co-processing scenarios (i.e., combinations of biofeedstocks and insertion points). In addition, there is no clear LCA method available to quantify the life cycle GHG emissions of co-processed fuels.

The objective of this study is to evaluate the CIs of various co-processing conditions in a typical petroleum refinery in the United States using a linear programming (LP) model. The LP model generates the mass and volume inputs and outputs of each processing unit at a refinery with and without co-processed biofeedstocks. We processed the LP model results and performed an LCA to examine the impact of co-processing in terms of life cycle GHG emissions.

Four types of biofeedstocks (soy oil, tallow, UCO, and pyrolysis oil) in three different refinery units (hydrotreater, hydrocracker, and FCC) have been evaluated to show how the life cycle GHG emission results would vary under different co-processing operation conditions. We present the CI values of co-processed fuels using two different LCA methodologies (process-level energy-based allocation and refinery-level marginal approach) to explore the impact and the limitations of LCA methodologies in calculating life cycle GHG emissions.

2. METHODOLOGY

2.1. System Boundary of Co-Processing of Biofeedstocks in Petroleum Refineries

The LCA system boundary of the co-processing of biofeedstock in an existing petroleum refinery is presented in Figure 1. It combines two pathways: The first petroleum pathway consists of crude oil production, crude oil transportation, crude oil refining, fuel transportation/distribution, and fuel combustion. In parallel, the biofeedstock inserted into one of the refinery units also has its upstream processes, including feedstock production (e.g., farming) and feedstock transportation. The remaining processes (fuel transportation and distribution and fuel combustion) are shared with petroleum products.

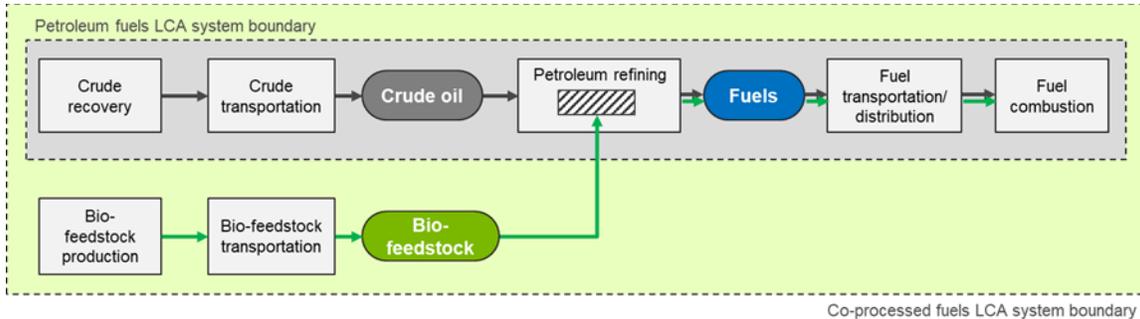


Figure 1. LCA system boundary of co-processing of biofeedstocks in an existing petroleum refinery.

This study focuses on evaluating the life cycle GHG emissions as measured in terms of carbon intensity (CI), which is presented in terms of grams of CO₂ equivalent per megajoule of fuel produced and used (gCO₂e/MJ) using 100-year global warming potentials based on the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) (IPCC 2013). Fuel transportation and distribution emissions are estimated at 0.4 gCO₂e/MJ. Note that this study does not consider the land-use change (LUC) impact of soybean production (other feedstocks are not subject to LUC).

2.2. Baseline Petroleum Refinery

This study required the development of a baseline refinery model that included three process units—hydrotreater, hydrocracker, and FCC—to analyze the co-processing of biofeedstocks in these units. The refinery configuration most likely to include these operations is a coking configuration in the U.S. Gulf Coast (USGC) area (Jenkins and DiVita 2017). Over 70% of the crude processed in the United States is in a coking configuration refinery (Oil & Gas Journal Research 2021), and 53% of the crude processing capacity is located in Petroleum Administration for Defense Districts 3 (PADD 3) (EIA 2021), which are mostly located on the Gulf Coast of Texas and Louisiana. This regional distribution led to the modeling of USGC coking for the baseline case configuration.

The baseline refinery represents a typical U.S. refinery that processes 100 thousand barrels per day (kBPd) of crude oil. Note that this is based on a standalone refinery configuration not an integrated refinery/petrochemical plant. In this study, the baseline USGC coking configuration processes a 30.3 API crude blend with 2.0% sulfur, composed of Maya, Mars, and light Louisiana sweet (LLS) crudes at the volumetric ratio of 20%, 50%, and 30%, respectively. Maya is a heavy sour crude produced in Mexico, Mars is from offshore drilling in the Gulf of Mexico, and LLS is light sweet crude oil from Louisiana. The crude slate was fixed for the comparison of baseline and co-processing LP modeling.

Product blending specifications are consistent with the USGC region during the winter season with more rigorous distillate specifications. The configuration produces gasoline, ultra-low-sulfur diesel fuel (ULSD; hereinafter diesel), jet fuel, and liquefied petroleum gas (LPG). It is assumed that all vacuum residual is fully converted to products (i.e., there is no production of any vacuum residual containing products). The refinery’s gasoline pool consists of 22% reformulated gasoline and 12% premium gasoline, a typical gasoline distribution in the United States. There is no production of naphtha, asphalt, specialty products, or residual fuel. The baseline case produces 10 kBPD of jet fuel (10% of crude throughput), consistent with average U.S. percentages.

2.3. Co-Processing Pathways

This study evaluates one baseline case (without biofeedstock inputs) and seven co-processing cases as shown in Figure 2. Different types of biofeedstocks have different characteristics (e.g., fatty acid composition) and vary in carbon chain length and degree of bond saturation, which results in different yields and hydrogen requirements. The lower heating values (LHVs) of the biofeedstocks are 36.8, 36.7, 36.9, and 16 MJ/kg for soy, tallow, UCO, and pyrolysis oil, respectively (GREET 2020). The detailed biofeedstock properties, collected from multiple sources and normalized, are presented in Table 1.

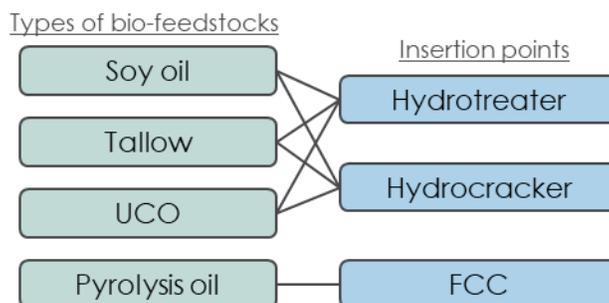


Figure 2. Co-processing pathways (combinations of the types of biofeedstocks and refinery units) evaluated in this study.

Table 1. Characteristics of three lipid feedstocks (soy oil, tallow, and UCO)

	Soy Oil	Tallow	UCO
Specific Gravity	0.9170	0.9020	0.9150
Free Fatty Acid	0.700	3.600	15.000
C12:0 Lauric Acid	0.02	0.05	0.00
C13:0 Tridecanoic Acid	0.00	0.00	0.00
C14:0 Myristic Acid	0.02	2.70	0.07
C14:1 Myristoleic Acid	0.00	0.00	0.00
C15:0 Pentadecanoic Acid	0.00	0.00	0.00
C15:1 Pentadecenoic Acid	0.00	0.00	0.00

	Soy Oil	Tallow	UCO
C16:0 Palmitic Acid	11.75	28.74	8.73
C16:1 Palmitoleic Acid	0.12	2.16	0.00
C17:0 Margoric Acid	0.03	0.25	0.00
C17:1 Heptadecenoic Acid	0.01	0.18	0.00
C18:0 Stearic Acid	4.13	22.97	3.69
C18:1 Oleic Acid	26.16	36.47	33.49
C18:1 Trans	0.00	0.00	0.00
C18:2 Linoleic Acid	52.42	5.82	47.93
C18:2 Trans	0.00	0.00	0.00
C18:3 Linolenic Acid	5.13	0.41	3.08
C18:3 Trans	0.00	0.00	0.00
C18:3a Gamma Linolenic Acid	0.00	0.00	0.00
C18:4 Stearidonic Acid	0.00	0.00	0.00
C20:0 Arachidic Acid	0.07	0.05	0.22
C20:1 Eicosenoic Acid	0.07	0.15	0.00
C20:2 Eicosadienoic Acid	0.00	0.00	0.00
C20:3 Eicosatrienoic Acid	0.00	0.00	0.00
C20:3 DGLA	0.00	0.00	0.00
C20:4 Archidonic Acid	0.00	0.00	0.00
C22:1 Erucic Acid	0.07	0.05	2.80
Total Wt%	100.00	100.00	100.00

(Ahmad Nizar et al. 2013, AVCalc LLC 2021, Bhatti et al. 2008, Evans et al. 1974, Gunstone 1996, Haigh et al. 2014, Rohman et al. 2014, Seifi et al. 2018, Selvam & Vadivel 2012, Tsoutsos & Stavroula 2013, USDA 2013).

As shown in Figure 2, we evaluated three lipid types of biofeedstocks (soy oil, tallow, and UCO) processed in either a hydrotreater or a hydrocracker. Hydrotreaters are where sulfur, aromatics, nitrogen, oxygen, and metals are reduced to meet fuel specifications (Schimmel et al. 2018), and hydrocrackers convert a heavy vacuum gas oil (VGO) stream into lighter diesel or jet fuel range products via catalytic cracking and high-pressure hydrogen. Hydrocrackers operate at a higher pressure than hydrotreaters and have a higher conversion of heavy feed into lighter products.

In this study, pyrolysis is co-processed only in the FCC unit. Pyrolysis oil has poor processing characteristics compared to other biofeedstocks because it has substantially higher oxygenate and water

content. The FCC unit in a refinery is typically used to upgrade a heavy fraction of crude through a catalytic cracking process that primarily produces gasoline along with some volume of distillate, LPG, slurry, and coke. This would lead to significantly higher hydrogen consumption or faster catalyst deactivation in hydrotreating or hydrocracking units. However, the FCC unit does not consume hydrogen, and the catalyst is regenerated instantaneously via coke combustion. The vast majority of U.S. refineries have FCC units, and some have pilot tested co-processing pyrolysis oil in their FCC operations. Therefore, we decided to include co-processing pyrolysis oil in the FCC, not in a hydrotreater or hydrocracker.

We modeled cases in which biofeedstocks make up 10 vol.% of the total feed to each of the three co-processing units. This is a typical co-processing level that should not cause changes in refinery infrastructure or significant operational changes (Bezergianni et al., 2018). Note that the 10% is not at the facility level (refinery crude throughput) but at the co-processing process unit level (FCC, hydrotreater or hydrocracker).

Each co-processing refinery unit has different processing capacities, which determine the volume of biofeedstock inputs. Given the unit capacity of the baseline LP refinery model, we have inserted biofeedstock of 3.2, 2.4, and 2.3 kBPD into the hydrotreater, hydrocracker, and FCC unit, respectively.

2.4. Linear Programming Modeling of a Petroleum Refinery

To simulate the changes in refinery operation caused by adding biofeedstocks to generate co-processed fuels, we used LP modeling for a refinery configuration with and without co-processing. The model provides representative responses to operational changes. Details can be found in the following sections.

LP methods are commonly used for refinery operation optimization. The proprietary LP model for this study utilizes GRTMPS (Generalized Refining Transportation Marketing Planning System) software by Haverly Systems (Haverly Systems 2021). The refinery database is designed for technical analysis and includes advanced algorithms for refinery process operations, feedstock quality impacts, blending specifications, stream quality predictions, and others. For this study, LP results have been generated with and without biofeedstock inputs.

Although co-processing is meant to involve a single unit taking both crude oil streams and biofeedstocks, we modeled the co-processing process to have a separate reactor taking biofeedstocks alongside the existing unit for petroleum, mainly because of the limited information about the reaction between petroleum feedstock and biofeedstock in a single large reactor. However, using two reactors for LP modeling purposes helps distinguish a crude-based product from a biogenic product in the model. We assumed these two streams would be mixed in the fuel product pool. Since there will be only one reactor in practice, with potential interaction between fossil and biogenic feedstocks, this LCA needs to be further refined with the datasets based on actual co-processing operations that may become available in the future.

The LP model refinery receives multiple triglyceride feedstocks with different levels of free fatty acids and converts these lipids in a hydrotreater. The model ensures balances on carbon, hydrogen, oxygen, sulfur, and nitrogen between all inputs and all outputs. In the modeled hydrotreater, it is assumed that oxygen in the feedstock is converted to water through hydrodeoxygenation, while some oxygen is converted to CO₂ (decarboxylation). Double-bonds are assumed to be 100% saturated with hydrogen inputs. The model accounts for carbon monoxide (CO) production and includes cracking reactions that produce incremental naphtha, LPG, and light gases (C1/C2).

In addition to the hydrocracker's main reactions of cracking heavy gas oils into middle distillate, the model also assumes that it can further crack diesel range intermediates into jet fuel, naphtha, LPG, and light gases (C1/C2), which would require the use of more hydrogen than does renewable fuel production in a hydrotreater. The model ensures that the properties of the products from both hydrotreater and hydrocracker are consistent with renewable diesel and jet fuel industry specifications.

Pyrolysis oil fed into the FCC unit was modeled based on the study by Talmadge et al. (2021), which provides a correlation for the FCC yields when co-processing pyrolysis oil. These correlations were developed directly from the experimental data from a demonstration-scale FCC unit. The multi-variable equation provides FCC yields as a function of two independent variables: weight percent pyrolysis oil input and FCC conversion efficiency. That equation was used to solve for the yield impact of pyrolysis oil in the feed, which was incorporated into the LP model.

We assumed that hydrogen is produced inside the refinery by the hydrogen plant or the reformer. The reformer hydrogen supply is a function of throughput and severity. Hydrogen produced at the hydrogen plant utilizes fossil-based natural gas for feed and fuel, and this combustion may contribute to the higher CI of the process as well as additional natural gas inputs.

2.5. Quantification of Biogenic Portion of Products

Determining bio-carbon content in co-processed fuels is important because only the biogenic portion of co-processed fuels is eligible for emission reductions in most regulatory frameworks (Schimmel et al., 2018). In actual co-processing cases, final fuel products (e.g., gasoline, diesel, and jet fuel) would include both fossil and biogenic elements without separation. The only information that refineries would have are the inputs (crude, biofeed, and other energy inputs such as natural gas and electricity) and outputs (each fuel product and emissions) unless biogenic carbon in each product is measured. That means that we need to either measure or estimate the biogenic carbon in each product using a robust and verifiable method.

Schimmel et al. (2018) and Lammens (2020) have reviewed various ways to quantify the biogenic portion of refinery products. One well-known method is to measure radiocarbon using accelerator mass spectrometry (AMS), i.e., carbon-14 (^{14}C) testing (Lammens, 2020), as documented in ASTM-6866 (ASTM International, 2012) and ISO-13833:2013 (ISO, 2013). This method measures biogenic carbon in a product by measuring the amount of radiocarbon, because fossil and modern carbon have different ratios. However, some argue that this method may be inaccurate considering the small biogenic portion of the fuel products (Lammens, 2020). Note that there are ongoing activities to develop new methods to measure biogenic carbon contents in liquid fuels. For example, liquid scintillation counting (LSC), with faster turnaround time and lower cost, may generate comparable results to AMS (Hurt et al. 2021).

Other methods of estimating biogenic carbon typically use the balance of mass or energy, as discussed in Schimmel et al. (2018) and Lammens (2020). Lammens (2020) suggested that the observed yield mass balance method would generate the most reliable results. The observed yields mass balance method attributes the differences in fuel production between the co-processing case and the baseline (using the same fossil crude without biofeedstock inputs) to be biogenic. Here, the issue is that biofeedstock with oxygen contents (e.g., pyrolysis oil) would generate non-fuel products such as CO_2 , CO , and water. In addition, some fuel products may have negative marginal differences. Other methods account for biogenic carbon in products using carbon, mass, or energy allocation. These methods assume that renewable inputs would be converted into all products in equal ratios (using carbon, mass, or energy). Another method, the free attribution method, allows the operator to choose how to allocate the renewable carbon in their products.

In this study, the LP model tracks where the product streams of the biofeedstock go by using two separate units (fossil and biogenic reactors) and labeling the output of each unit differently. Although the final product would be a mixture of both fossil and biogenic sources in practice, the energy-based process-level allocation (see the section below) based on the LP modeling results can provide the allocated energy share of biogenic carbon in each product slate by subtracting the biofeedstock that ultimately ends up as GHG emissions from the co-processing unit, as fuel gas, and as FCC coke.

2.6. LCA Methodology of Co-Processed Fuels

Co-processed fuels may have different direct and indirect emissions due to the changes in inputs and outputs (energy products and emissions) and depending on the operating conditions. Even if we know exactly how much carbon in the product comes from biogenic sources, through various methods explained in the previous section, we do need to account for emissions and allocate these to the energy products correctly. In the following sections, we present two different methods of allocating energy use and emissions in a refinery to the fuel products.

LCA also requires accounting for the energy use and emissions associated with all life cycle stages, from feedstock production to fuel combustion, as shown in Figure 1. The refinery LP results would provide only mass/volume inputs and outputs at each process unit at the refinery, which varies depending on the co-processing conditions. Therefore, for a WTW analysis, it is essential to account for all upstream and downstream impacts in addition to allocating refinery energy use and emissions. In this study, for upstream and downstream processes, we relied on the GREET[®] (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) model (GREET 2020) leveraging the previous studies on petroleum and biofuel production and use. The GREET model is an LCA tool that includes all relevant upstream processes of all the inputs (energy and chemicals such as crude oil, biofeedstock, electricity, and natural gas) and downstream processes (fuel transportation and combustion). Note that waste feedstocks (UCO and tallow) do not take production-associated energy and emission burdens; we only accounted for the processes starting from feedstock collection and transportation for these feedstocks.

In LCAs, biogenic carbon emissions are considered carbon-neutral because the carbon in biofeedstocks originates from CO₂ in the atmosphere. Biogenic carbon emissions from the refinery are assumed to be from carbon uptake, and similarly, biogenic carbon emissions from fuel combustion would be also from carbon uptake.

2.6.1. Process-Level Energy Allocation Approach

Process-level energy allocation is used for typical LCAs of petroleum-derived products (Elgowainy et al., 2014). Even without biofeedstocks, refineries have multiple energy inputs, such as crude oil, natural gas, and electricity, while generating multiple outputs, such as gasoline, diesel fuel, jet fuel, and LPG. Each product goes through a different refining process with different energy requirements and yields. For example, jet fuels go through fewer refining processes than gasoline and diesel, which results in lower CIs for jet fuel than for gasoline and diesel fuel. In each refining process, intermediate or final products share the process emissions and input energy burdens based on the energy contents of the process outputs (or products). By aggregating the burdens from different refining units to the final product pools (e.g., gasoline, diesel fuel, and jet fuel), inputs and emissions can be allocated to each product (Elgowainy et al., 2014). Detailed descriptions of process-level energy allocation methods can be found in Elgowainy et al. (2014).

For the co-processing cases, we used the same process-level allocation approach to allocate energy use and emissions to the refinery products. The methodology is identical to other petroleum refinery LCAs, except for the fact that the co-processing cases would have a new input (biofeedstock) and carbon-neutral biogenic emissions. Biofeedstock inputs and associated process emissions are allocated to each product. Biogenic carbon emissions that are treated to become carbon neutral during the refining process may reduce refinery CIs. In addition, biogenic carbon in fuels would reduce emissions from the use of final fuels through carbon neutral biogenic CO₂ emissions, which is why quantifying the biogenic portion in fuels is important.

This method generates product-specific CI values for various co-processing conditions, which can be compared to LCA studies on petroleum products without co-processing. However, this method might not generate separate CIs for the renewable fuel portion. This is because the renewable streams and fossil streams produced from the co-processing units are pooled together and go into the subsequent downstream processes simultaneously until this pool is blended into the final product pool. However, the energy-allocation method would result in the same CI for different renewable fuel types.

2.6.2. Refinery-level Marginal Approach

Lammens (2020) mentioned that the observed yields mass balance method could be used to estimate renewable fuel volumes. The concept is that the changes in fuel products from adding additional biofeedstock with the normalized crude oil inputs makes them renewable fuels. Expanding the rationale, the changes in energy use and emissions in refineries caused by co-processing can be allocated to the changes in fuel output (renewable fuels). This emission allocation method can be called a refinery-level marginal approach, which needs both the petroleum-only baseline case and co-processing cases as presented in Figure 3. This approach was adopted by California Air Resources Board (CARB, 2017).

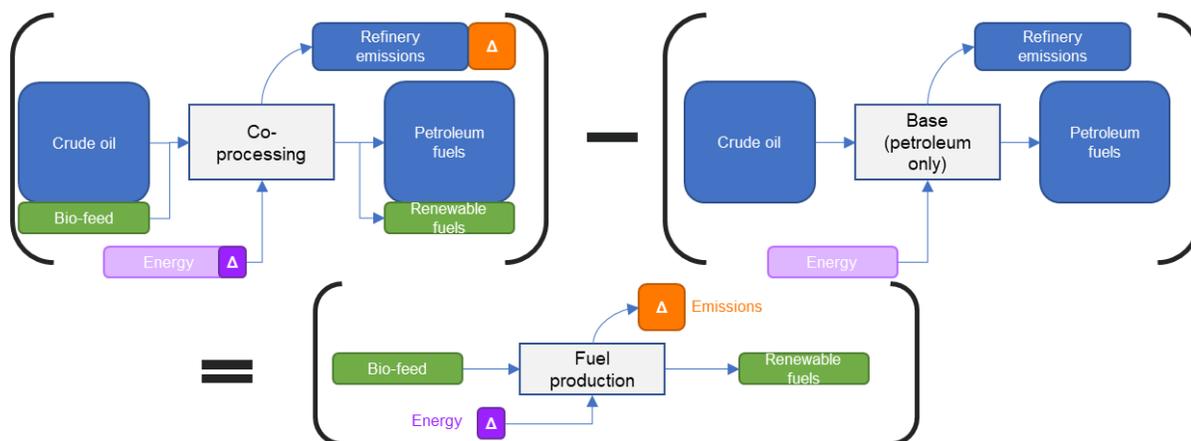


Figure 3. Refinery-level marginal approach for CI calculation of renewable fuels (based on CARB’s marginal approach).

The refinery-level marginal approach attributes changes in emissions (gCO₂e) to estimated renewable fuel production. In addition, changes in energy use in the refinery would change upstream emissions (from the production and transportation of the energy inputs), which are also allocated to renewable fuels. In our study, the upstream CI values of energy inputs for NG, butane, and electricity are estimated at 10.6, 16.2,

and 125 gCO₂e/MJ, respectively (GREET 2020). Upstream emissions related to biofeedstock production and transportation, in gCO₂e, are also allocated to renewable fuels. Biofeedstock upstream emissions are estimated at 13.1, 9.9, 3.5, and 9.9 gCO₂e/MJ biofeedstock for soy oil, tallow, UCO, and pyrolysis oil, respectively (GREET 2020). This refinery-level marginal approach does not separate types of fuel products (gasoline, diesel, jet fuel, and other fuel products). Consequently, the CIs of all renewable fuels are the same, regardless of the type of product. The advantage of the refinery-level marginal approach is that it simplifies the CI estimation of co-processed renewable fuels using the input and output data that refineries generally measure and collect. However, these datasets are required for similar refinery conditions with and without biofeedstock inputs.

3. RESULTS AND DISCUSSION

3.1. Facility-Level Inputs and Outputs

We found that the co-processing cases in this study, using 10 vol.% biofeedstock in each co-processing unit, do not significantly change overall facility-level inputs and outputs. Figure 4a presents energy inputs by energy type (crude oil, biofeedstock, NG, butane, and electricity) in terms of MJ total fuel product, which varies in a very narrow range of 1.134–1.135 MJ/MJ. Since the inverse of the energy inputs (per MJ energy output) represents the overall refinery efficiency, the results show that there is no noticeable change in conversion efficiency. In the co-processing cases, the green sections of the bars represent biofeedstock-related energy inputs, which replace 1%–3% of total crude oil energy inputs to produce results virtually identical to the baseline.

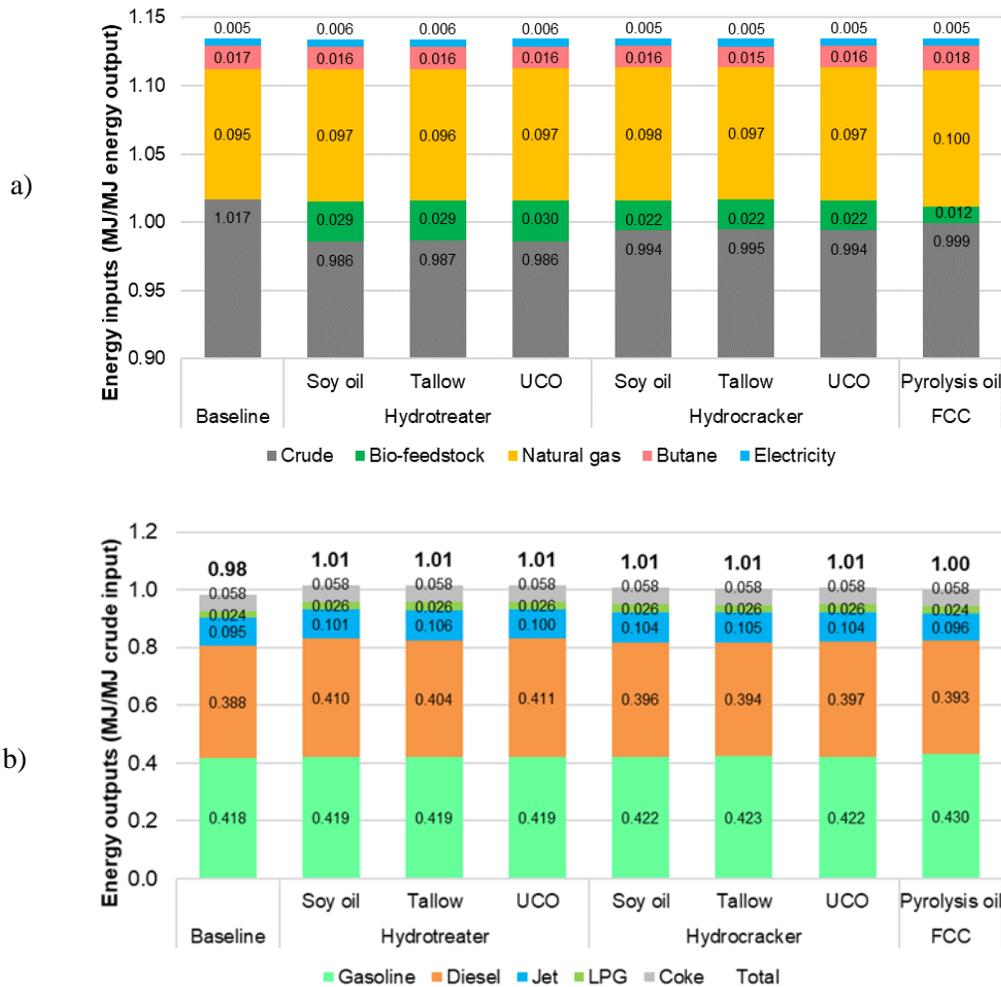


Figure 4. a) Energy inputs for baseline and co-processing cases in terms of MJ total energy output. b) Energy outputs by fuel type for baseline and co-processing cases in terms of MJ crude oil input.

To show the changes in refinery outputs with the same crude oil input, the output products are presented in terms of MJ crude oil inputs in Figure 4b. Co-processing cases have additional biofeedstocks inputs resulting in slightly higher energy output yields: 1.01 MJ/MJ of crude for the hydrotreater and

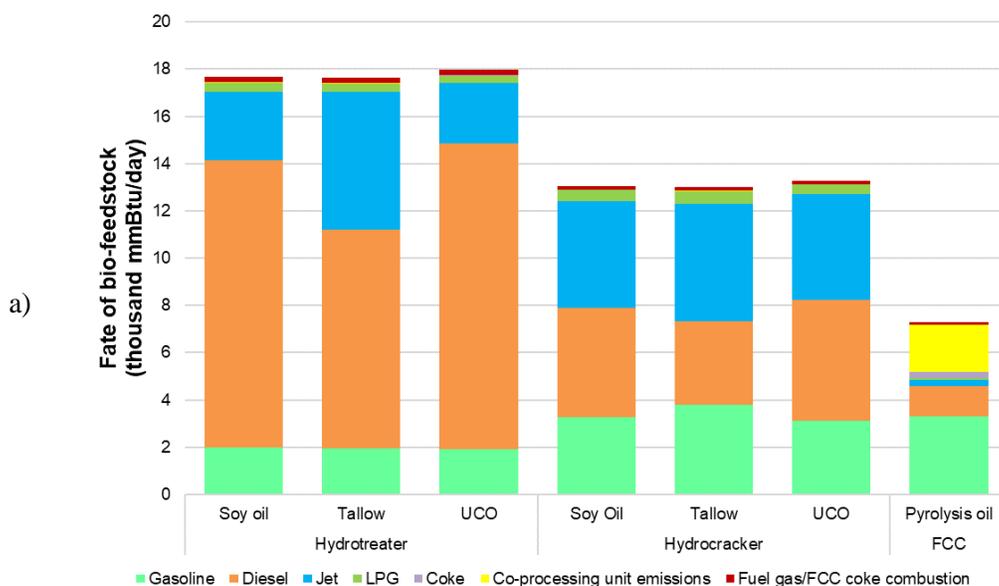
hydrocracker co-processing cases and 1.00 MJ/MJ for the FCC co-processing case compared to 0.98 MJ/MJ for the baseline case without biofeedstock. The results of product splits show that there are no noteworthy impacts on finished blending with co-processing at the facility level, although the hydrotreater and hydrocracker have increased diesel and jet fuel production, in part from the incremental biofeedstock feeds, and the FCC processing pyrolysis oil has increased gasoline yield.

3.2. Fate of Biofeedstocks

It is essential to track the route of biofeedstock-derived products through the refinery to analyze the impact of co-processing.

Figure 5 presents the fate of biofeedstocks in the refinery in terms of energy content: Biofeedstocks may ultimately be destined for products such as gasoline, diesel, jet fuel, LPG, or coke, or even emitted as process emissions during the conversion processes. The last is shown as co-processing unit emissions, refinery fuel gas combustion, and FCC coke combustion.

The processing capacities of three refinery co-processing units (hydrotreater, hydrocracker, and FCC) are different, as mentioned earlier. That is, 10 vol.% biofeedstock in each co-processing unit results in different total biofeedstock energy inputs for hydrotreater, hydrocracker, and FCC co-processing units, and consequently each co-processing case has different bio-energy outputs (Figure 5a). In addition, the energy content of each feedstock is different, which results in slightly different values among three types of lipids biofeedstocks for the hydrotreater and hydrocracker. Pyrolysis oil, due to its low LHV caused by higher oxygenate and water content, has the smallest biofeedstock energy input, though the unit capacities of the hydrocracker and FCC are similar.



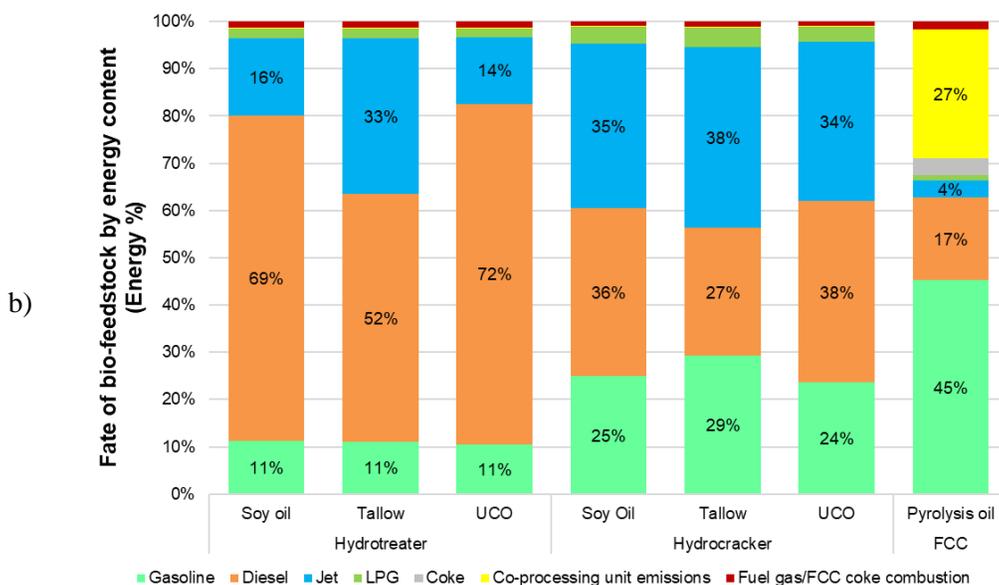


Figure 5. The fate of biofeedstocks: products (gasoline, diesel, jet, LPG, and coke) and emissions (co-processing unit emissions and fuel gas/FCC coke combustion emissions). a) Total energy in products in the modeled refinery and b) energy content in terms of percentage.

Figure 5b shows the share of biofeedstock energy in the outputs. It can be seen that hydrotreaters generate mainly diesel range fuels because the biofeedstocks consist mainly of molecules with C16–C18 backbones (Table 1), which lie in the diesel range. In contrast, hydrocracking breaks long carbon chains into shorter chains and so produces more gasoline and jet range fuels. Hydrotreaters do not have the capability for significant cracking reactions, while hydrocrackers generate cracking reactions that result in more biofeedstocks in jet fuel (34%–38%) than hydrotreater (14%–33%) and FCC (4%) co-processing cases. Tallow has a higher jet fuel fraction for the hydrotreater case because tallow has a higher share of C16 than other lipids feedstocks, and these are converted into jet range fuels through hydrotreating, which means that the biofeedstock properties play an important role in determining the product slate. Although the absolute yield of naphtha in the hydrotreater and hydrocracker is small compared to the distillate yield, the naphtha percentage increase is over three times higher in the hydrocracker than in the hydrotreater, which drives the strong percentage increase in gasoline production in the hydrocracker compared to the hydrotreater co-processing cases. This is because more significant naphtha-producing cracking reactions take place in the hydrocracker than in the hydrotreater.

Pyrolysis oil in the FCC unit produces lower energy product yields (Figure 5a) with higher emissions (29%) than other co-processing cases. For FCC co-processing, naphtha blended into the gasoline pool drives strong gasoline production (45%) compared to other cases. A small portion of pyrolysis oil energy input (4%) is converted to jet fuel production in the FCC co-processing case. As pyrolysis oil has a much higher oxygen content than triglyceride content, the FCC case has lower yields than the hydrotreater and hydrocracker co-processing cases. In addition, the FCC unit burns coke from the feedstock to drive the process, which inherently results in more feedstock loss to emissions.

3.3. LCA Results Using Process-level Energy Allocation

An LCA using process-level energy allocation presents the CI of each fuel product, which varies depending on the energy use and emissions from each process. Figure 6a shows the refinery emissions allocated to gasoline, diesel, jet fuel, and LPG with fossil feedstock and biofeedstocks combined. The baseline cases present product-specific GHG emissions results representing the petroleum-only case. Major refinery emissions are from refinery fuel gas combustion, natural gas steam methane reforming (NG SMR) for hydrogen production, FCC coke combustion, and process emissions from co-processing units. Figure 6 shows that the CI trend among the products is similar to the earlier LCA study on U.S. petroleum refineries (Elgowainy et al., 2014).

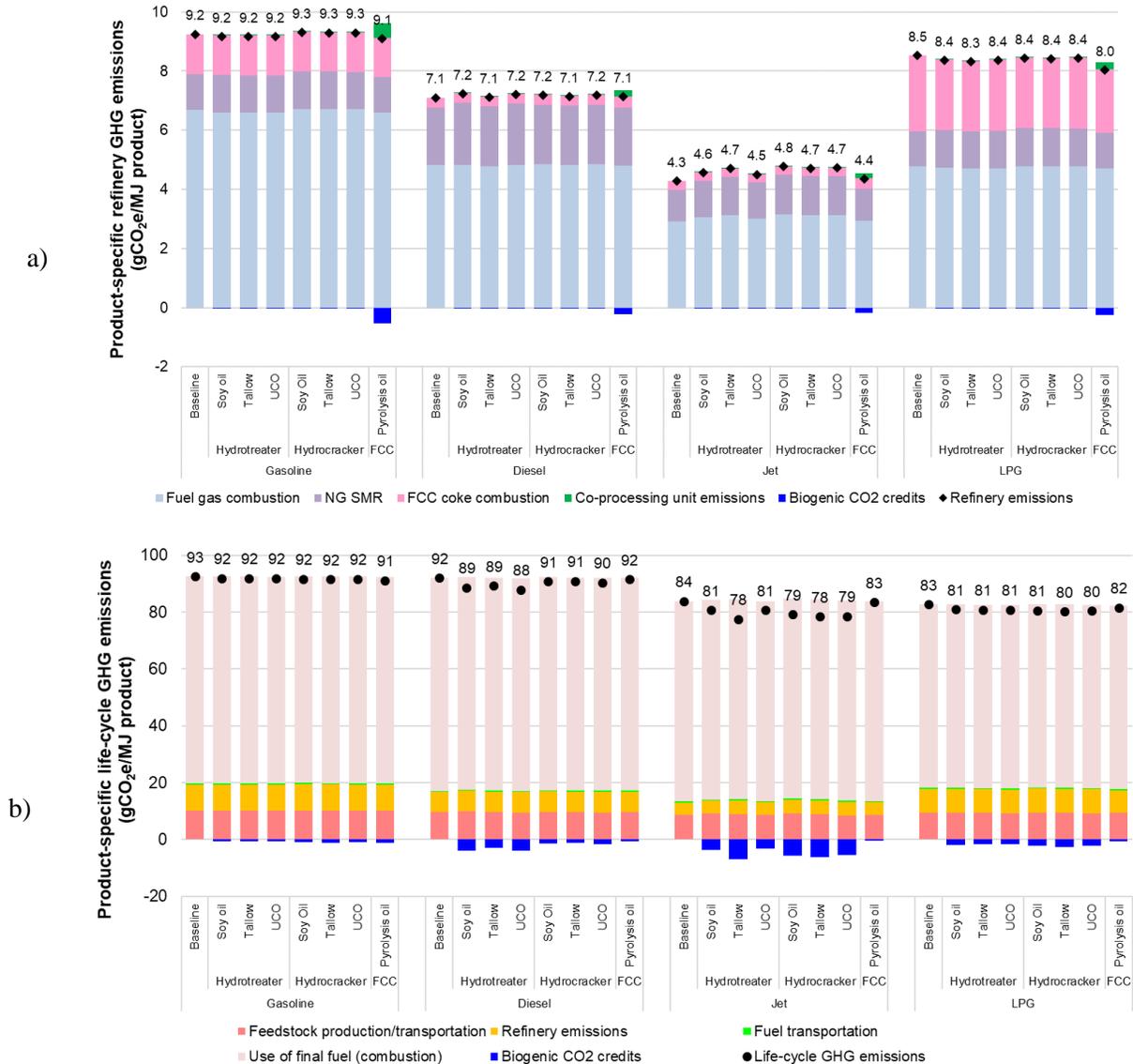


Figure 6. LCA results of co-processing using process-level energy allocation for gasoline, diesel, jet, and LPG compared with the baseline case: a) Product-specific refinery GHG emissions, and b) product-specific life cycle WTW GHG emissions, both in terms of gCO₂e/MJ of each product with combined crude and biofeedstock. The LUC impact associated with soybean production has not been considered.

Figure 6a shows that the pyrolysis FCC co-processing cases are noticeably different from the baselines. FCC co-processing cases in Figure 6a show slight reductions in the overall refinery CIs for gasoline and LPG, mainly because a high fraction of pyrolysis oil (29% of biofeedstock energy input) becomes biogenic CO₂ emissions from the co-processing unit, offsetting other refinery emissions, while the hydrotreating and hydrocracking co-processing cases turn biofeedstocks mostly into energy products (Figure 5). In the hydrotreating and hydrocracking co-processing cases, the refinery CIs for diesel and jet fuel show slight increases in NG SMR emissions due to increased hydrogen demand for the conversion processes.

The process heat and hydrogen demands for diesel and jet fuels from the hydrotreater and hydrocracker with biofeedstocks are slightly higher than the demands with fossil feedstock (the baseline case). The fossil jet fuels for the baseline case are mainly from a straight run stream of crude requiring less hydrotreating and less hydrogen consumption than co-processing cases with a hydrotreater or hydrocracker. Therefore, co-processed diesel and jet fuels from a hydrotreater or hydrocracker have higher overall refinery emissions associated with fuel gas combustion and hydrogen production from NG SMR than the baseline cases.

When it comes to life cycle GHG emissions, including the entire supply chain from feedstock production to the use of the final fuel for combustion (Figure 6b), the results show the CI values are mainly driven by biogenic CO₂ credits (blue bars) while other emission contributions are mostly constant. This means that the amount of biogenic carbon embedded in each fuel would be the key driver determining the CI of each final fuel product. Figure 7 shows the energy percentage of bio-derived fuels in each product for each co-processing case, which is closely related to CO₂ credits in Figure 6b. The biogenic portion of co-processed diesel and jet fuels are 1.5%–5.3% and 4.3%–9.2% of the final diesel and jet fuel pools on a MJ basis, respectively (Figure 7).

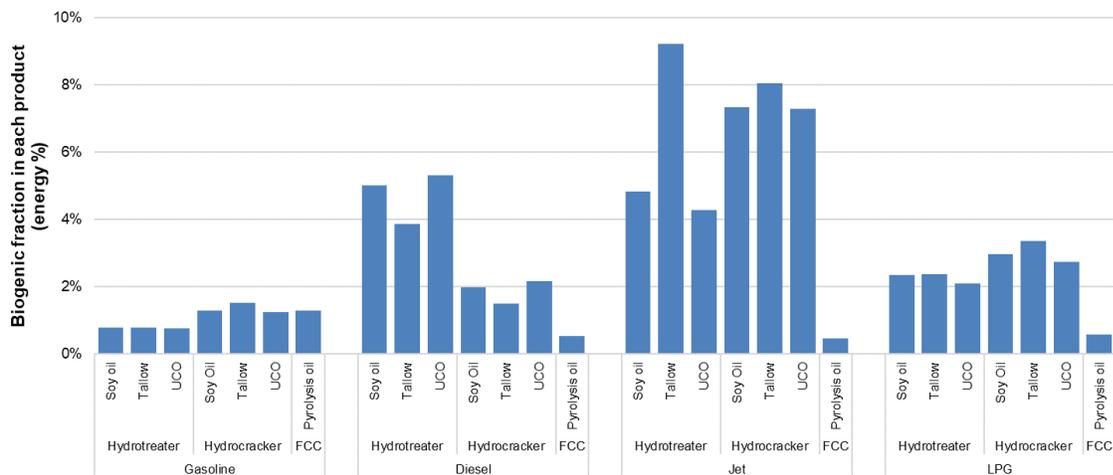


Figure 7. Biogenic fraction in terms of energy content allocated in each product for the co-processing cases.

Co-processed jet fuels from the hydrotreater and hydrocracker show 3.7%–7.5% life cycle GHG emission reductions: CIs of 78–81 gCO₂e/MJ, compared to the baseline jet fuel CI of 84 gCO₂e/MJ. Co-processed diesel from the hydrotreater and hydrocracker shows 3.0%–4.5% and 1.1%–1.8% life cycle GHG emission reductions: CIs of 88–89 gCO₂e/MJ for the hydrotreater and 90–91 gCO₂e/MJ for the hydrocracker, compared to the baseline diesel CI of 92 gCO₂e/MJ, mainly due to biogenic carbon in the

product (Figure 7). Co-processed gasoline fuels and FCC co-processed fuels do not offer much life cycle GHG emission reduction benefit due to their lower biogenic fraction.

As mentioned earlier, the process-level energy allocation approach does not generate renewable-fuel-specific CIs. It is very challenging to separate the renewable CIs from the combined results in Figure 6b, because fossil- and bio-derived fuels go through different processes in the refinery, and the upstream impacts of crude oil and biofeedstocks are different.

However, considering that the changes in product-specific refinery emissions for each product is so small in all seven cases with 10 vol% co-processing (in Figure 6a), we may calculate product-specific life cycle GHG emissions of co-processed renewable fuels, assuming constant refinery emissions. Once we set refinery emissions as constant, the LCA of co-processed biofuels becomes similar to other biofuel production pathways, similar to the supply chain presented as green arrows in Figure 1. Only the biofeedstock inputs (MJ biofeedstock per MJ biogenic fuel production) and feedstock production and transportation CIs ($\text{gCO}_2\text{e}/\text{MJ}$ biofeedstock) are needed to estimate upstream emission impacts. For downstream, the same fuel transportation impact can be used. Since we evaluated biogenic fuels, combustion emissions are carbon neutral.

Figure 8 presents the product-specific WTW GHG emissions of co-processed renewable gasoline, diesel, jet fuel, and LPG using the accounting framework and assumptions above, which show significant emissions reductions compared to their petroleum baselines (72%–90% on a MJ basis). Refinery emissions vary by the type of fuel product. As in the petroleum WTW results, jet fuel has the lowest CIs compared to other fuels. The CIs of feedstock production and transportation and fuel yield also lead to variations in the co-processing types. The differences in feedstock production CIs in soybean, tallow, and UCO contribute significantly to the WTW results, as the hydrotreater and hydrocracker cases have quite similar conversion efficiencies (1.0–1.1 MJ biofeedstock is needed for 1 MJ biofuel production). On the other hand, FCC cases require much more biofeedstock, around 1.4 MJ pyrolysis oil to produce 1 MJ co-processed biofuel. Thus, FCC cases have higher feedstock production impacts than tallow cases, while the feedstock production CIs of pyrolysis oil and tallow are similar.

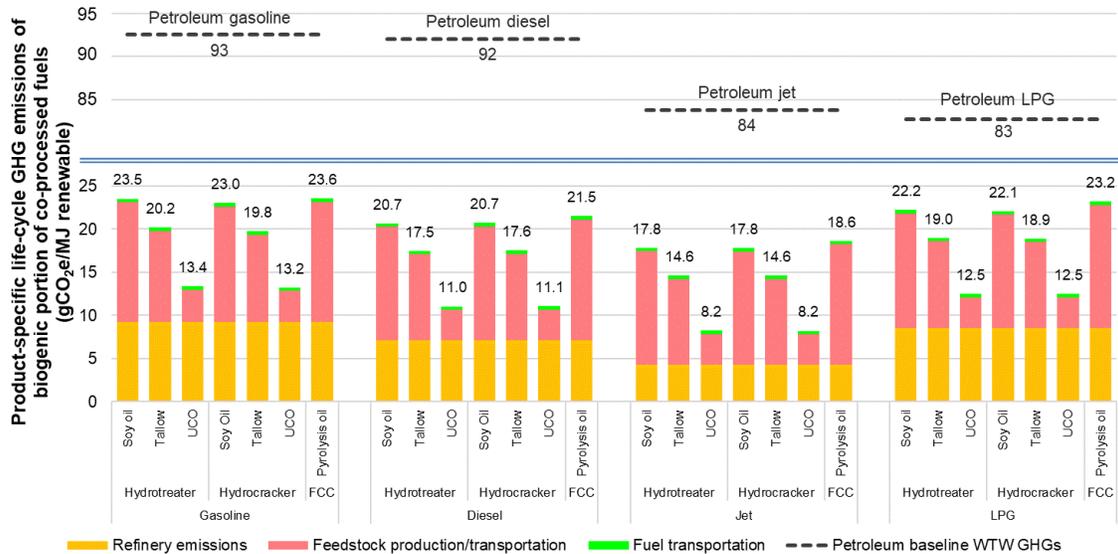


Figure 8. Product-specific WTW GHG emission results of co-processed renewable fuels for gasoline, diesel, jet fuel, and LPG in terms of gCO₂e/MJ renewable fuels, compared with the WTW GHG emissions of petroleum products from Figure 6.

3.4. LCA Results Using Refinery-level Marginal Allocation

If all differences between the refinery energy use and emissions of co-processing cases and the baseline cases are allocated to the changes in energy outputs (assuming renewable fuels), we can generate the CIs of renewable fuels, although this does not generate renewable fuel product-specific CI results. Table 2 presents the inputs and outputs (i.e., products and emissions) of the cases. For the co-processing cases, the numbers represent the changes (delta) compared to the baseline case with the normalized crude inputs. The baseline case generates 1 MJ of energy products using the crude input of 1.017 MJ. The changes in refinery emissions from FCC combustion, NG SMR, refinery fuel gas combustions, and co-processing units are divided by the changes in energy products to calculate the refinery emissions per MJ renewable fuels.

Section (a) of Table 2 presents energy inputs, energy outputs, and emissions without separating fossil from biogenic. We believe that this is the accounting framework of CARB’s marginal approach. In our LP modeling, we were able to separate fossil and biogenic portions of inputs/outputs/emissions and deduct biogenic CO₂ emissions from total refinery emissions. We present net biogenic fuel production and emissions with biogenic credits in section (b) of Table 2. To estimate refinery emissions with co-processing, only non-biogenic CO₂ emissions should be accounted for.

Table 2. Refinery inputs and outputs of the baseline case and co-processing cases represented as the changes (delta) compared to the baseline case. The baseline case generates 1 MJ of total energy products. Section (a) shows the marginal approach and (b) shows the marginal approach with the fate of biofeedstocks.

	Base	Delta from the base						
		Hydrotreater			Hydrocracker			FCC
		Soy oil	Tallow	UCO	Soy oil	Tallow	UCO	Pyrolysis oil
(a) Refinery-level marginal approach								
Input (kJ)	1,134	35	34	36	26	25	27	20
Crude	1,017	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biofeedstock	0	30.4	30.3	30.9	22.4	22.4	22.8	12.5
NG	95	4.8	3.8	4.6	4.6	3.9	4.4	6.4
Butane	17	-0.3	-0.3	-0.3	-0.9	-1.3	-0.9	0.9
Electricity	5	0.6	0.5	0.6	0.4	0.4	0.4	0.1
Products (kJ)	1,000	31.5	30.7	31.4	23.2	22.3	23.1	17.4
Gasoline	425	1.6	8.4	1.6	4.2	3.7	-1.5	12.3
Diesel	395	23.3	9.3	22.3	8.2	8.5	13.3	5.2
Jet fuel	97	4.8	10.1	5.6	8.6	8.2	10.1	0.0
LPG	25	1.7	2.3	1.9	2.1	1.9	1.7	-0.4
Coke	58	0.0	0.5	0.0	0.0	0.0	-0.4	0.4
Emissions (g)	7.58	0.29	0.24	0.28	0.28	0.25	0.27	0.45
FCC coke combustion	0.82	0.00	0.00	0.00	0.00	0.00	0.00	0.01
NG SMR	1.42	0.16	0.13	0.16	0.13	0.11	0.12	0.04
Refinery fuel gas combustion	5.34	0.13	0.10	0.12	0.15	0.14	0.15	0.07
Co-processing emissions (fossil and biogenic CO ₂)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.34
(b) Refinery-level marginal approach with the fate of biofeedstocks								
Renewable content in fuel products (kJ)		29.9	29.9	30.5	22.1	22.1	22.5	8.9
Emissions w/biogenic credits (g)		0.26	0.21	0.25	0.26	0.23	0.25	0.10

When the refinery-level marginal approach is used, CIs can be calculated by dividing total emissions changes by total fuel production changes. Figure 9a shows that the refinery marginal emissions of co-processed renewable fuels range from 7.8 to 9.3 gCO₂e/MJ for hydrotreater cases and from 11.1 to 12.1 gCO₂e/MJ for hydrocracker cases, and are 25.9 gCO₂e/MJ for the FCC case. The hydrocracker requires more process heat and hydrogen inputs per unit of final fuel production, and thus higher allocated emissions from refinery fuel gas combustion and NG SMR, than the hydrotreater.

Once the changes in upstream emissions are considered, based on the delta energy inputs to the refinery (NG, butane, and electricity) to support additional process heat and hydrogen demands, the upstream

emissions associated with refinery delta energy inputs are estimated at 3.1–5.6 gCO₂e/MJ (Figure 9a). The sum becomes the refinery CI of renewable fuels produced from co-processing, using the refinery-level marginal approach, which is estimated at 11.1–13.1 and 14.2–15.8 gCO₂e/MJ renewable fuels for hydrotreating and hydrocracking, respectively. The pyrolysis oil FCC case has the highest refinery CI of 31.5 gCO₂e/MJ, mainly because emissions from the co-processing FCC unit, including both fossil and biogenic emissions, are overestimated when biogenic emissions are not differentiated from fossil emissions. In

Figure 5b, 29% of FCC co-processing biofeedstock energy input becomes biogenic CO₂ emissions, which is not considered carbon neutral emissions as the marginal approach does not differentiate between fossil and biogenic inputs, outputs, and emissions.

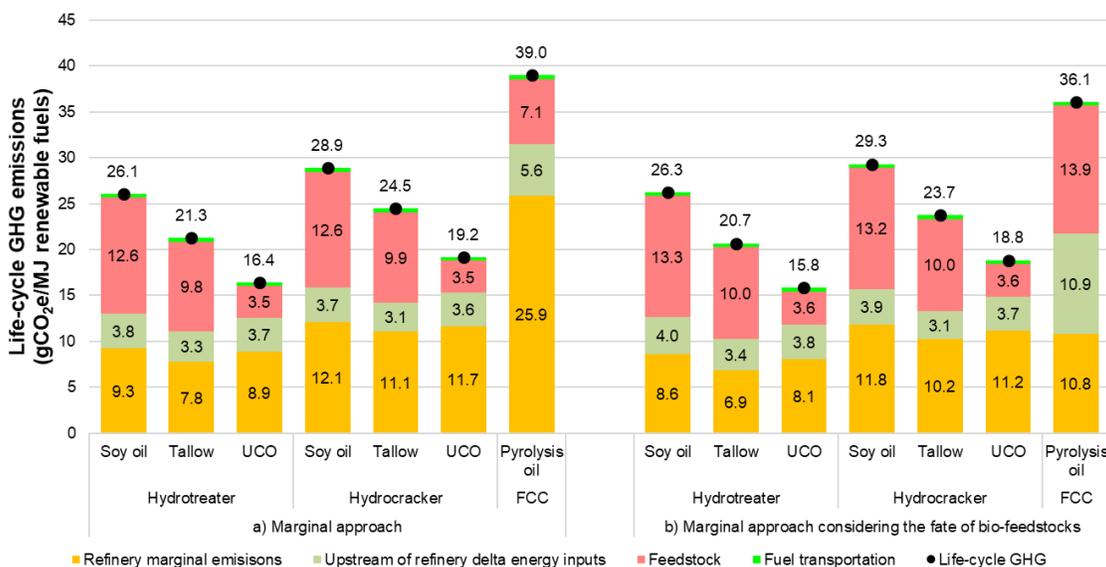


Figure 9. Life cycle GHG emissions of co-processed renewable fuels calculated using a) marginal approach (left-hand figure) and b) marginal approach considering the fate of biofeedstocks (right-hand figure). The LUC impact associated with soybean production has not been considered.

Including the impact of feedstock production (red bars in Figure 9a) along with the refinery CIs, the life cycle GHG emissions of the co-processed renewable fuels, calculated using the marginal approach, become 16.4–26.1 for hydrotreating cases, 19.2–28.9 for hydrocracking cases, and 39.0 gCO₂e/MJ renewable fuels for the FCC co-processing case. These CI values are comparable to standalone biofuel production pathways, e.g., 22 gCO₂e/MJ for soybean renewable diesel, 25 gCO₂e/MJ for tallow biodiesel, and 26 gCO₂e/MJ for pyrolysis diesel (GREET 2020).

However, in practice, the refinery-level marginal approach does not differentiate between biogenic and fossil emissions from the refinery. Thus, considering that co-processing of biofeedstocks in FCC would generate significant biogenic emissions, the refinery CI of FCC co-processing could be quite distorted using the refinery-level marginal approach due to inaccurately estimated yield and emission values. While refinery emissions are overestimated by accounting for biogenic emissions, upstream (feedstock production and delta energy inputs) impacts are underestimated by not considering lower fuel yield when using biofeedstocks in the FCC.

Because the LP model tracks the fate of biofeedstocks (Figure 5), we can better estimate biogenic fuel fractions in total fuel production and refinery emissions

given the biogenic CO₂ credits. These may be different from actual practice using the refinery-level marginal approach. Section (b) of Table 2 shows the renewable fuel portion of the final fuel products, given the fate of biofeedstocks, in the refinery-level marginal approach. The renewable energy in fuel products for hydrotreating and hydrocracking are all slightly lower than the marginal energy production. However, the results show that the pyrolysis FCC case has only 8.9 kJ renewable fuels in 1017.4 kJ fuel production. The significant difference is again mainly driven by the biofeedstock fraction converted into emissions, not fuels. If we consider biogenic refinery emissions to be carbon neutral, there is a slight decrease in emissions for the hydrotreating and hydrocracking cases compared to the marginal emissions, due to the biogenic emission credits. On the other hand, a significant fraction (29% in Figure 5) of pyrolysis oil inserted into FCC would turn into co-processing emissions. Thus, considering the biogenic carbon neutrality in the refinery, refinery emissions for the pyrolysis FCC case become 0.10 gCO₂e, which is much less than the marginal emissions of 0.45 gCO₂e that include both fossil and biogenic emissions.

Once renewable fuel production is estimated using LP and changes in emissions considering biogenic credits (Table 2b), the life cycle GHG emissions results (Figure 9b) become different from the original marginal approach (Figure 9a). Refinery emissions are reduced by the amount of biogenic emissions for the adjusted renewable fuel production. All hydrotreating and hydrocracking cases have slightly lower refinery emissions due to biogenic emission credits. Further, FCC refinery emissions show a significant reduction due to biogenic emissions from the FCC unit, while renewable fuels are estimated to be lower. Delta energy and feedstock production impacts are driven by the adjusted biogenic fuel production, which becomes higher in Figure 9b.

4. CONCLUSIONS AND DISCUSSIONS

This study evaluated, using LP modeling, the GHG emissions implications of co-processed biofeedstocks in a petroleum refinery. In order to evaluate the emissions reduction of co-processing, it is important to quantify the biogenic portion of fuel products—through estimation and/or measurement—and calculate the CIs of fuel products. To quantify the biogenic portion of fuel products, we estimated using mass balance with LP results, and to calculate the CIs of fuel products, two different LCA methodologies were used: a process-level energy allocation approach and a refinery-level marginal approach. In the refinery model, three types of lipids biofeedstocks (soy oil, tallow, and UCO) were fed into petroleum hydrotreater or hydrocracker processes, and pyrolysis oil was fed into a petroleum refinery FCC unit, all at 10 vol.% of the co-processing unit capacity.

The results show that this level of co-processing (10 vol.% biofeedstock at the processing unit) does not significantly vary the operation of the modeled refinery in terms of energy efficiency or product slate at the facility level. The LP results show that biofeedstocks are mostly converted into final fuel products in the hydrotreating and hydrocracking co-processing cases, while a large fraction of biofeedstock is converted into coke and refinery fuel gas which becomes process emissions in the FCC case. The process-level energy allocation approach, a typical LCA method used for petroleum LCAs, generates CIs by fuel type (gasoline, diesel, jet fuel, and LPG) in terms of MJ of fuel products, which can be compared to other petroleum LCA results. The results show that the refinery CIs do not show significant changes from co-processing. The major reductions in life cycle GHG emissions come from biogenic carbon in final fuel products. Co-processing using hydrotreating and hydrocracking reduces the CIs of jet fuel 3.7%–7.5% compared to the CI of baseline petroleum jet fuels. Similarly, diesel production through hydrotreating and hydrocracking of biofeedstocks potentially reduces GHG emissions by 1.1%–4.5% compared to the CI of baseline diesel fuels. Since co-processed jet fuels contain a larger biogenic portion than diesel fuels, jet fuel shows a higher CI reduction on a MJ fuel basis. Co-processing of pyrolysis oil in an FCC does not provide significant emission reductions, mainly due to higher oxygenates and water content in the biofeedstock that turn into process emissions (i.e., 29% biofeedstock loss to emissions). It is the least renewable fuel production among the co-processing cases investigated.

As refinery emissions do not vary with 10 vol.% biofeedstock inputs at the co-processing unit level, we estimated product-specific WTW GHG emissions of the biogenic portion of co-processed fuels. The biogenic CI values are 72%–90% lower than the petroleum baseline CIs on a MJ basis.

With the assumption that the differences in fuel production between the co-processing cases and the baseline (petroleum only) case are due to renewable fuels, the impacts of all the changes in refinery emissions and energy inputs are allocated to the renewable fuels. This refinery-level marginal approach enables the calculation of the CIs of renewable fuels, although it does not produce product-specific CIs, unlike the process-level allocation approach. The refinery-level marginal approach results are mainly driven by the changes in refinery emissions with the changes in hydrogen and process heat requirements in the refinery. The results show that co-processing using a hydrotreater, hydrocracker, and FCC unit produce CIs comparable to standalone biofuel production pathways. We further used LP results to evaluate whether the refinery-level marginal approach is based on a valid assumption. While hydrotreating and hydrocracking cases show similar results, even when the LP estimated renewable fuel volume and emissions with biogenic credits, the FCC case shows quite different estimated fuel production and emissions, mainly due to its large losses to process emissions.

Although this study does not account for the LUC impact of soybean production, it should be noted that LUC may add significant GHG emissions to the WTW GHG emissions of the soybean co-processing cases calculated in this study. For example, standalone soybean-derived biofuel production (renewable diesel or bio-diesel) may incur additional 9–32 gCO₂e/MJ (Kwon et al. 2021, CARB 2014, ICAO 2019, EPA 2020). In addition, we modeled co-processing with two separate reactors for fossil feedstocks and biofeedstocks. Further studies based on actual co-processing data are needed to confirm whether the LP results and subsequent analysis results are reasonable.

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